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STAFF FORECAST OF 2008 PEAK DEMAND

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INTRODUCTION AND BACKGROUND

This document describes staff's draft forecast of 2008 peak demand for the major utilities, control areas, and load serving entities (LSEs) in California. The methods and accuracy of the methodology used to develop the year-ahead forecast are also discussed. This forecast will be presented at a workshop on May 24, 2007, after which it may be revised before adoption by the California Energy Commission (Energy Commission). Staff's draft 10-year annual peak and energy demand forecast will be published in June 2007 as part of the 2007 *Integrated Energy Policy Report (IEPR)*.

The final 2008 peak demand forecasts for the respective territories of the state's three investor-owned utilities (IOUs)—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—will serve as a reference case for the California Public Utilities Commission's (CPUC) 2008 resource adequacy process. The CPUC determined in its resource adequacy proceeding that the Energy Commission demand forecast, as the "state's official load forecast," should serve as the reference case in the resource adequacy load forecast review and adjustment process implemented by Energy Commission staff.¹ The final forecast of 2008 for CPUC-jurisdictional LSEs will be applied to hourly forecast load shapes to develop a monthly peak forecast for each service area. If the sum of the year-ahead forecasts submitted by load serving entities (LSEs) is more than one percent different from the Energy Commission forecast, staff adjusts the LSE forecasts to within one percent, as directed by the CPUC. These adjusted forecasts must be used in the LSE's year-ahead compliance filing with the CPUC, in which they demonstrate that they have contracted in advance for resources sufficient to cover 90 percent of their forecasted peak demand. The Energy Commission forecast may also be used by the California Independent System Operator (California ISO) for the allocation of import capabilities, in grid planning studies, and in other applications.

The Energy Commission's most recent forecast of peak demand was adopted in June 2006.² This forecast, the June 2006 Update, is the basis for the 2007 resource adequacy forecasts under which LSEs now operate, and combines an analysis of loads and temperatures in summer 2005 with growth rates from the most recent adopted 10-year Energy Commission forecast,³ which was prepared for the 2005 *IEPR* and adopted in September 2005. The September 2005 forecast was based on historic energy consumption and peak demand through 2004.

¹ Rulemaking 04-04-003, Decision 05-10-042, October 27, 2005, [http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/50731.htm].

² California Energy Commission, *Staff Forecast of 2007 Peak Demand*. June 2006. Publication no. CEC-400-2006-008-SF.

³ California Energy Commission. *California Energy Demand 2006–2016, Staff Energy Demand Forecast, Revised September 2005*. Staff final report. Publication no. CEC-400-2005-034-SF-ED2.

SUMMARY OF RESULTS

To develop the 2008 peak demand forecast, staff first estimated the relationship between temperature and daily summer afternoon peak demand for each service or planning area. This estimated equation was then applied to the historic average of annual maximum temperatures in order to develop an estimate of weather-normalized demand for 2006. Weather normalization estimates what loads would have been assuming average - or 1-in-2 - weather conditions. Finally, the 2006--2008 growth rate from the September 2005 demand forecast was used to produce a revised annual peak forecast for 2008.

Many applications of the Energy Commission forecast require that forecasts be disaggregated to individual LSEs. Resource adequacy applications also require the segregation of CPUC-jurisdictional loads from non-jurisdictional loads. Staff used hourly loads for individual LSEs within the planning areas or zones to disaggregate the forecast. Weather-normalized loads were also estimated for sub-areas of the California ISO for comparison with the sum of LSE-specific results.

Table 1 shows the results of this analysis. In Northern California, weather-normalized loads overall were somewhat higher than forecast. The PG&E service area forecast is increased by 1.9 percent, and the PG&E transmission planning area forecast is 3.0 percent higher. The SMUD forecast is 3.7 percent higher. In the SCE area, load growth was slower than projected and the forecast is revised down 1.6 percent. The SDG&E forecast is 1.2 percent higher. Because of the offsetting changes in the north and south, the California ISO forecast is unchanged. Overall the forecast for the state is 1.2 percent higher.

Tables 10 and 11 at the end of this report present more detailed results. The remainder of this document describes the methodology and data used for each utility area forecast.

**Table 1: Revised versus June 2006 Peak Demand Forecast
Megawatts (MW)**

		June 2006 Update Forecast of 2006	2006 Weather- Normalized	Staff Forecast 2008	% Change from June 2006 Update (2006)
	PG&E Service Area	19,162	19,523	20,057	1.9%
	PG&E Area CAISO LSEs	1,233	1,206	1,239	-2.2%
	Dept of Water Resources - North	409	409	409	0.0%
	Total North of Path 15	20,804	21,137	21,705	1.6%
	Turlock Irrigation District Control Area	482	570	587	18.1%
	Sacramento Municipal Utility District	2,995	3,106	3,252	3.7%
	Other SMUD/WAPA LSEs	1,349	1,594	1,633	18.1%
	Total SMUD Control Area	4,345	4,700	4,885	8.2%
	Total PG&E Planning Area (excl. DWR & SMUD)	22,227	22,892	23,516	3.0%
	SCE Planning Area	22,791	22,417	23,091	-1.6%
	Pasadena Water and Power	296	310	310	4.5%
	San Diego Gas & Electric	4,384	4,438	4,586	1.2%
	Dept of Water Resources - South	506	506	506	0.0%
	Total South of Path 15	27,977	27,670	28,493	-1.1%
	Sum of Noncoincident Peaks in CAISO Control Area	48,781	48,807	50,198	0.1%
	CAISO Coincident Peak	47,613	47,639	48,996	0.1%
	LADWP	5,779	5,958	5,999	3.1%
	Burbank	288	292	292	1.2%
	Glendale	304	302	302	-0.6%
	Total LADWP Control Area	6,371	6,552	6,593	2.8%
	Imperial Irrigation District	869	958	985	10.2%
	Sum of Noncoincident Peaks	60,849	61,587	63,248	1.2%
	Statewide Coincident Peak Demand	59,392	60,112	61,733	1.2%

GENERAL WEATHER NORMALIZATION METHODOLOGY

Staff used Federal Energy Regulatory Commission (FERC) Form 714 hourly load data and utility planning area daily temperatures to estimate the relationship between summer weekday afternoon (1 p.m.–6 p.m.) peaks and temperatures. The reported peak impacts of demand response and interruptible programs were added to the recorded load. Summer is defined as the period from June 15 to September 15 for purposes of this analysis. The temperature variable for each utility is the weighted average of temperatures from a set of weather stations representative of the climate in that particular utility’s region (Table 2). Because residential air conditioning is the primary driver of day-to-day changes in peak demand, weather station weights are based on the estimated number of residential air conditioning units in each of the utility forecast zones assumed in the Energy Commission’s residential demand forecast model. In 2006, staff modified the weights of PG&E’s weather stations in order to more accurately reflect the distribution of air conditioners.

Table 2: Planning Area Weather Weighting Factors

PG&E	Ukiah	Sacramento	Fresno	San Jose	San Francisco
	0.067	0.169	0.413	0.282	0.069
SCE	Fresno	Long Beach	Burbank	Riverside	
	0.062	0.324	0.243	0.371	
SDG&E	Lindbergh Field	Miramar	El Cajon		
	0.333	0.333	0.333		
LADWP	Long Beach	Burbank			
	0.42	0.581			

Two separate weather variables were calculated for this analysis. The first is a weighted average of maximum temperatures for three days (*max631*). This weighting consists of 60 percent of the current day’s maximum temperature, 30 percent of the previous day’s maximum temperature, and 10 percent of the second previous day’s maximum temperature. This lag is used to account for heat build up over a three-day period. The “1-in-2,” or normal peak temperature, is derived from annual maximum temperature, for the years 1950-2006, for both PG&E and SCE. The time period for the SDG&E planning area was limited to 1979–2006 because daily weather data was not continuously available for El Cajon before 1979.

The daily temperature spread, or diurnal variation (*divar*), is the second temperature variable. This variable is the daily maximum temperature less the daily minimum temperature. It serves as a proxy measure of daily humidity. The assumption is that the lower the daily temperature spread for a given temperature, the higher the daily

humidity—for example, a day with a maximum temperature of 95 degrees Fahrenheit (F) and a minimum of 75 degrees F is likely to be more humid than a day with a maximum temperature of 95 degrees F and a minimum temperature of 65 degrees F. This proxy is used because there is little available historic information on humidity for long time periods for most weather stations, while daily maximum and minimum temperatures are readily available. The daily diurnal variation is not lagged since its purpose is to provide a measurement of the actual daily humidity, which in turn affects the physical need for air conditioning compressors to take water vapor out of the air.

The daily afternoon peak demand is regressed against *max631*, *divar*, and a variable identifying weekends and holidays. To derive the demand under 1-in-2 temperatures, the estimated coefficients are applied to the historic daily temperatures to calculate predicted annual maximum peak demands. The predicted annual peaks represent the distribution of possible peak demands under the weather conditions that have been observed since 1950. The median of the predicted annual peaks is the weather-normalized, “1-in-2,” peak demand.

PG&E PLANNING AREA RESULTS

The PG&E transmission planning area includes the PG&E service area and an additional 3,000 MW of load served by other LSEs. For Silicon Valley Power (SVP), the Northern California Power Agency (NCPA), Turlock Irrigation District (TID), Modesto Irrigation District (MID), and the cities of Redding and Roseville, staff used 2006 hourly load data to estimate a weather-adjusted peak. For smaller utilities where hourly load data is not available, staff estimated the peak from annual energy consumption and compared that peak estimate with reported or forecasted peaks from other data sources including supply forms filed as part of the *2007 IEPR*.

After compiling peaks for individual LSEs and adjusting for coincidence, staff compared the aggregate of the California ISO LSE peaks with weather-normalized peaks for California ISO loads north of path 15 (NP 15). The aggregate coincident weather-normalized peaks are within 0.25 percent of the weather-normalized 2006 NP 15 peak.

PG&E Service Area Results

Estimates of weather-normalized peak demand can vary significantly depending upon data and methods used. In comparing forecasts for the June 2006 Update, Energy Commission and PG&E staffs differed significantly in their respective estimates of weather-normalized peak demand. Weather stations used by PG&E resulted in a lower MW-per-degree response to increasing temperatures than did the weather stations used by Energy Commission staff. Below-average maximum temperatures in 2005 contributed to uncertainty over the most accurate estimate of weather-normalized 2005 service area peak. The weather-normalization method assumes that the temperature/load relationship estimated from the below-average temperatures experienced in the summer of 2005 is equally valid at 1-in-2 temperatures. Because of the lack of consensus on this issue, the final June 2006 Update forecast used the midpoint of the Energy Commission and PG&E estimates as the base value.

Above-average temperatures in 2006 allow us to better evaluate the predictive ability of the weather data used in the staff forecast. Figure 1 presents June 2006 estimates using 2005 daily peaks for both staff and PG&E weather analyses. It also contains the 2006 projected peak value, using actual July 2006 temperatures. The actual peak of 21,356 MW is 0.3 percent above the estimated peak using the staff method, but is 5.3 percent above estimated peak using the PG&E weather model. Based on these results, staff concludes that its original weather normalization methodology provides a more accurate estimate of the actual peak and will use it in this forecast update.

Figure 2 presents the temperature and loads for both the 2005 and 2006 summer weekday periods (June 15 through September 15). Also shown are the estimated peaks at the 1-in-2 temperature for each year, and the June 2006 Update forecast. It

is interesting to note differences in the overall temperature ranges of the two respective summer periods.

Figure 1: PG&E Peak Estimation Method Comparison

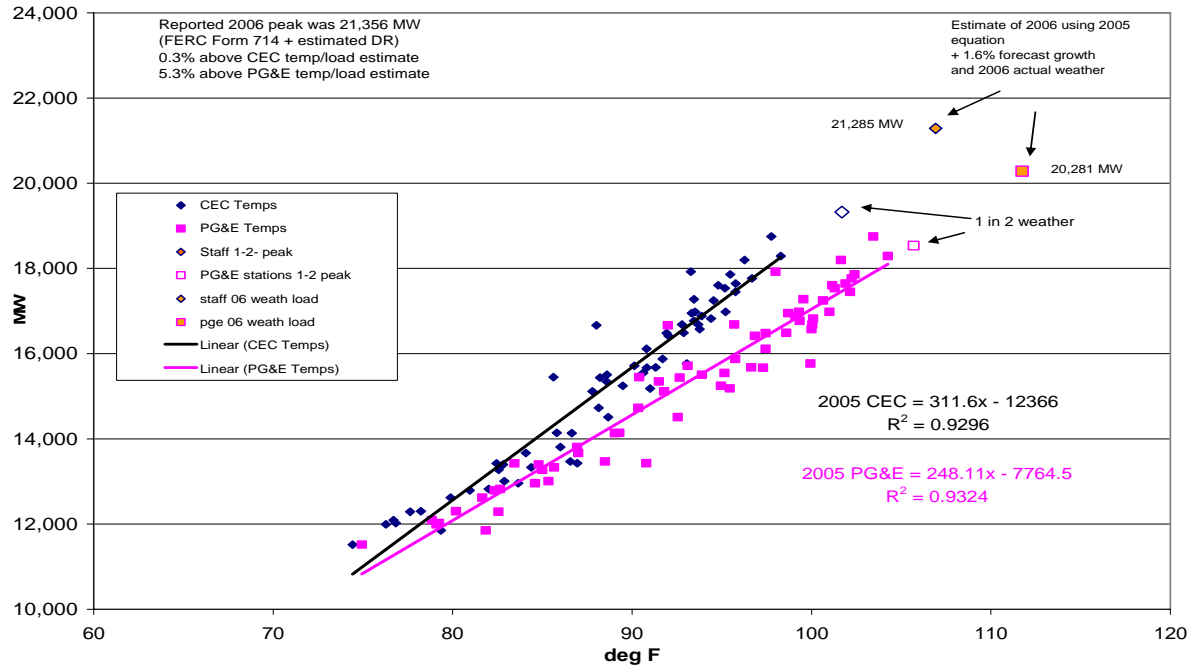


Figure 2: PG&E Summer Weekday Temperature versus Peak

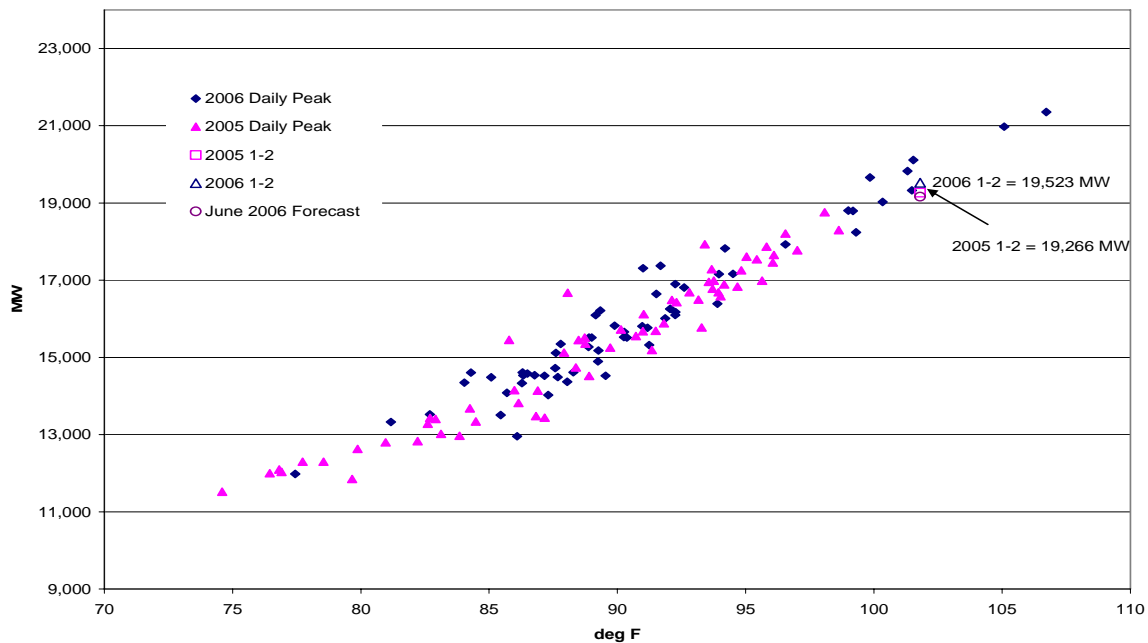


Table 3 shows staff's estimated coefficients and the resulting forecast. The revised weather-adjusted estimate for 2006 is 1.9 percent higher than the averaged 2006 estimate upon which the June 2006 Update forecast for 2007 was based. The proposed forecast for 2008 of 20,057 MW is slightly higher (by 89 MW) than PG&E's forecast, submitted in January 2007 as part of the Energy Commission's 2007 IEPR proceeding.

Table 3: PG&E Service Area Forecast

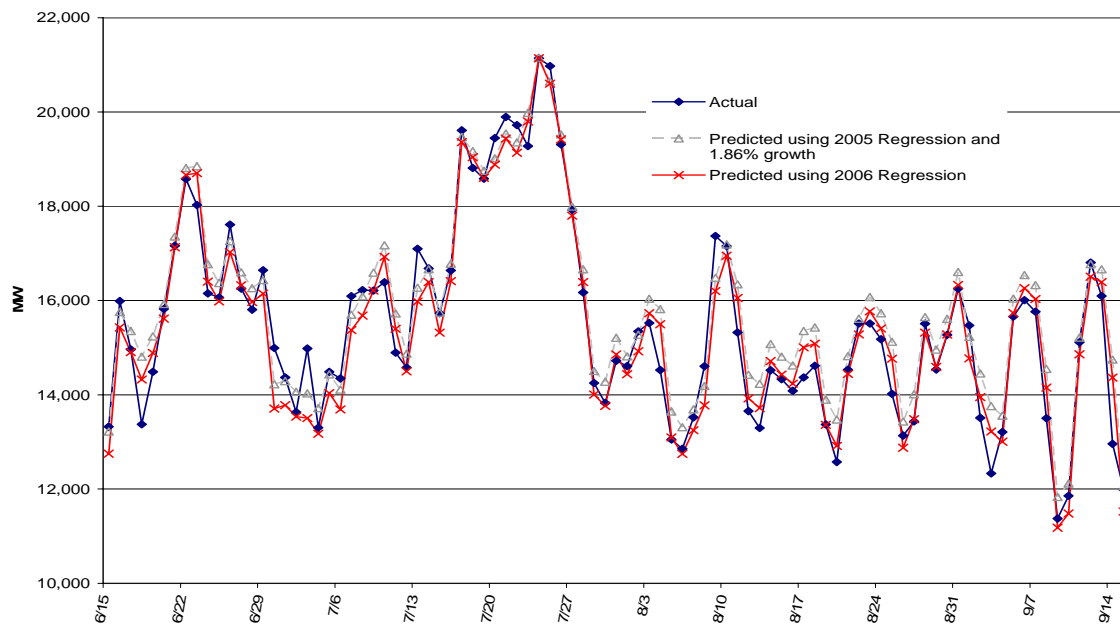
Estimated Temperature-Load Statistics for 2006						
	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Statistic</i>			
Intercept	-13,896.33	770.65	-18.03			
Weekend/Holiday	-1,561.90	104.58	-14.93			
PG&E631Max	328.28	8.45	38.83			
Adjusted R Square	0.95					
Staff PG&E Service Area Forecast					PG&E's 2007 IEPR Forecast of 2008	% Difference Staff/LSE Forecast
Weather Scenario	Weather Normalized 2006	2007	2008	% Increase above 1-in-2		
1-in-2	19,523	19,807	20,057		19,968	0.99%
1 in 5	20,048	20,340	20,597	2.69%		
1 in 10	20,245	20,540	20,799	3.70%		
1-in-20	21,065	21,373	21,643	7.90%		

Table 3 also shows the staff forecast under extreme temperature conditions. Because the extreme temperatures of 2006 are included in the weather history, which used to generate the probability of high-load events, the weather scenario multipliers have increased slightly.

Forecast Accuracy

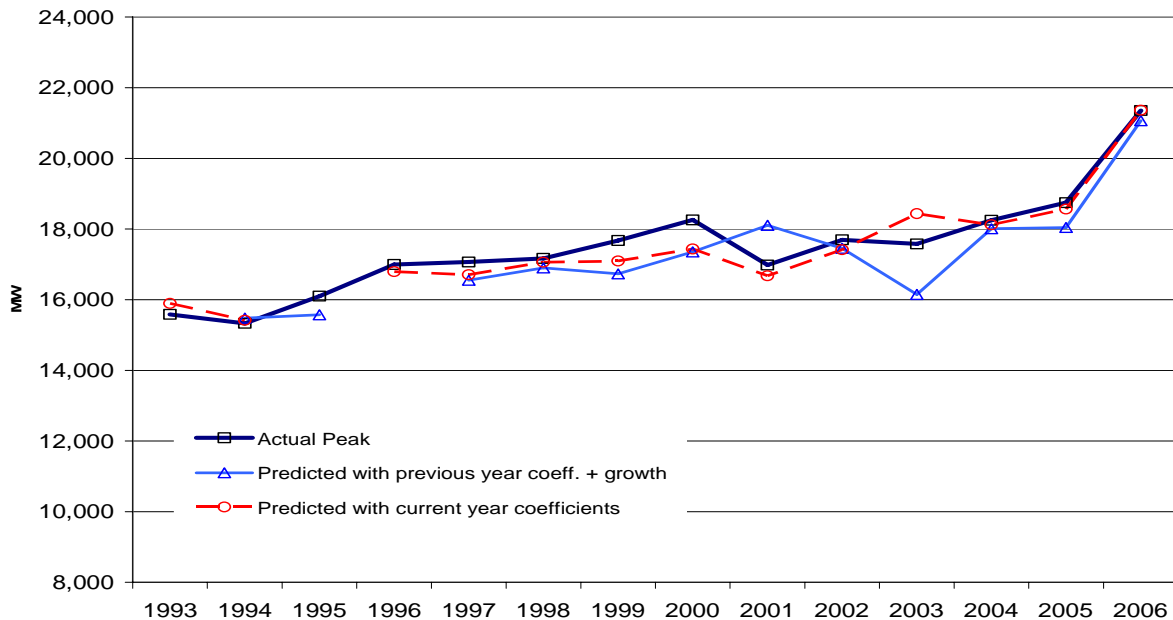
Figure 3 presents a comparison of actual summer 2006 daily peaks with estimated daily peaks derived from both the 2006 estimation equation and the 2005 estimation equation grown at the 2005–2006 adopted forecast growth rate. The staff weather model using the 2005 estimates has a mean absolute percentage error of 3.2% percent over the summer of 2006. The error of the 2006 model is 2.4 percent. Based upon these results, staff recommends the staff weather station weightings (shown in Table 2) to develop a year-ahead summer 2008 peak forecast.

Figure 3: 2006 PG&E Service Area Predicted versus Actual Peaks



To further evaluate the accuracy of the method used to develop year-ahead peak forecasts, staff compared the weather-normalized peak (which would have been predicted with past years' weather data and forecasts) with actual loads that occurred at that temperature. Staff estimated the weather coefficients for the PG&E service area for the years for which hourly loads are available—1993 through 2006. For each of those years, a year-ahead temperature load model was constructed by combining the coefficients estimated from the previous year's load and temperature data with annual growth from the most recent adopted forecast. For example, the year-ahead model for 1994 combines coefficients estimated from 1993 daily peaks and temperatures with the 1993–1994 growth rate (2.2 percent) from the 1992 *Electricity Report* demand forecast. This model was then applied to the actual temperatures occurring for each summer day in 1994. From these predicted daily peaks, the annual maximum peak (given the daily weather that actually occurred) is extracted. Figure 4 compares these hypothetical year-ahead forecasts with actual peak demands.

Figure 4: PG&E Actual versus Predicted Annual Peaks 1993–2006



The predictions of peak using current-year coefficients have an absolute average error of 1.9 percent. Using the previous years' coefficients with a forecasted growth rate increases the average error to 3.5 percent. The largest error in year-ahead forecasts is in 2003, when the economic driver used predicted a decline of the Northern California economy that did not occur. Similarly, the method under-forecasts during the technology boom of 1999 to 2000.

PG&E Area Publicly Owned Utilities (POUs)

Table 4 shows staff's revised forecast for the major POUs in Northern California, the previous Energy Commission forecast, and, for those who submitted demand forecasts in the 2007 IEPR proceeding, the POU's own forecast. The Energy Commission's POU forecasts were not updated as part of the June 2006 Update; the comparison shown is therefore to the 2005 IEPR forecast. That forecast disaggregated the PG&E area total based upon shares of 2003 actual,—not weather-adjusted loads.

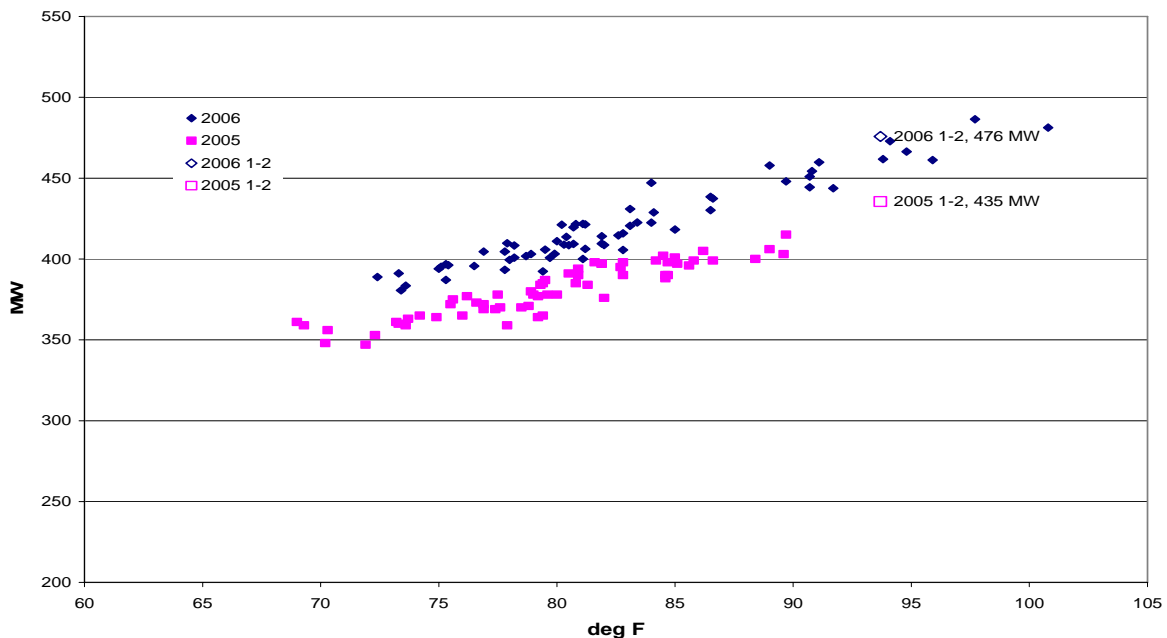
Using 2006 weather-adjusted loads significantly increases the estimated peaks of most LSEs. In all cases, staff's revised forecast is within 3 percent of the forecast submitted by the POU. In the remainder of this section, temperature-load relationships for 2005–2006 are shown for the three largest POUs: SVP, MID, and TID.

Table 4: 2008 Peak Forecasts for Northern California POUs

LSE	2005 IEPR Forecast of 2006	Weather-Normalized 2006 Peak		% Change from June 2006 Update	Staff Forecast of 2008	LSE'S 2007 IEPR Forecast of 2008	% Difference Staff/ LSE Forecast
		Co- incident	Non- coincident				
SVP	380	469	473	23.2%	486	485	0.3%
NCPA LSEs	510	480	485	-5.8%	498		
Other CAISO LSEs	343	257	262	-25.1%	269		
TID	404	493	498	22.0%	513	517	-0.7%
Merced Irrigation District	78	77	77	-1.9%	79		
Central Valley Project	244	251	251	2.7%	251		
MID	525	662	669	26.2%	689	711	-3.0%
Redding	203	244	246	19.9%	253	257	-1.5%
Roseville	299	331	332	10.5%	342	339	0.9%

Figure 5 shows loads and temperatures for Silicon Valley Power (SVP). The results indicate 2005–2006 peak growth of 9 percent. SVP notes in its 2007 IEPR demand forecast submittal that they experienced an increase in energy consumption of about 7 percent in fiscal year 2006 as commercial and industrial vacancy rates declined. The staff's weather-normalized peak produces a forecast of 486, nearly identical to SVP's forecast.

Figure 5: SVP 2005 – 2006 Summer Weekday Temperature versus Peak



The next two charts show temperature-load trends for MID and TID. Both LSE's load grew 2 percent from 2005 to 2006, slightly faster than the Energy Commission forecast growth rate.

Figure 6: MID 2005 – 2006 Summer Weekday Temperature versus Peak

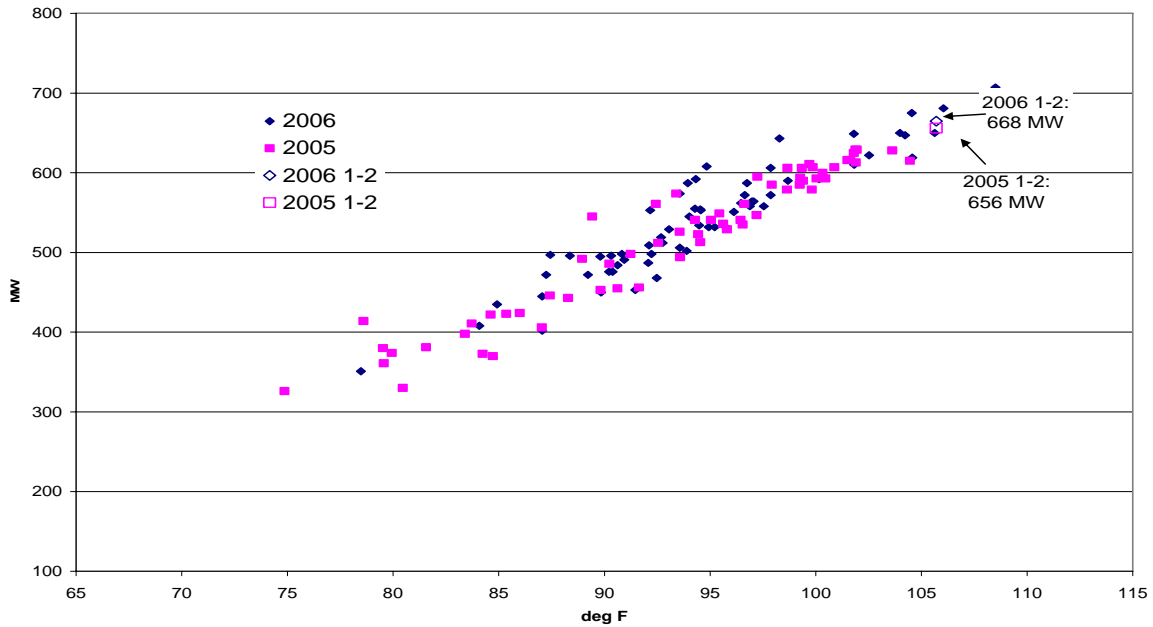
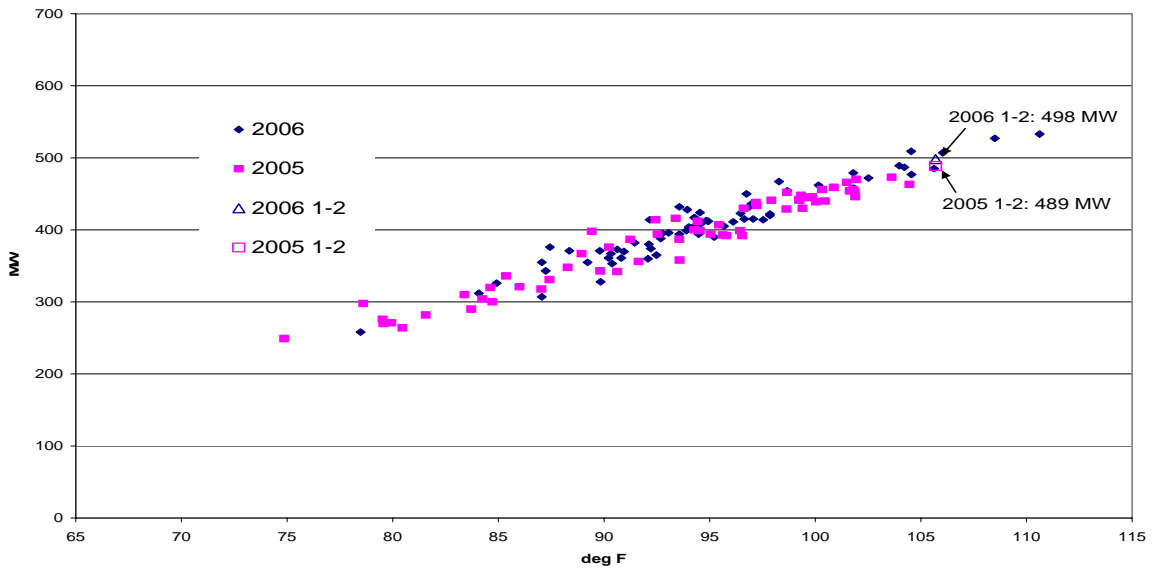


Figure 7: TID 2005 – 2006 Summer Weekday Temperature versus Peak



SCE PLANNING AREA RESULTS

Unusual weather conditions during the summer of 2005 prompted staff to introduce the use of daily diurnal variation in addition to temperature. Staff continues to use both lagged temperature and daily diurnal variation for the weather normalization procedure for the SCE planning area.

Figure 8 shows 2005 and 2006 summer weekday temperatures and peaks. Also shown is each year's weather-normalized 1-in-2 peak estimates. On average, 2006 summer weekday service area temperatures were somewhat higher than in 2005. Other than the difference in the peak week temperatures, the most notable difference is the group of 2005 temperatures on the low end of the range. The difference in weather-normalized 1-in-2 peak estimates for both years, however, is less than 0.5 percent, indicating essentially no growth in peak demand after adjusting for temperature. By comparison, weather-adjusted demand from 2004 to 2005 grew by 4.6 percent—nearly 1,000 MW. This slowing growth may reflect the effects of both weakening economic conditions and increasing rates in the SCE service area.

Figure 8: SCE 2005 – 2006 Summer Weekday Temperature-Peak Comparison

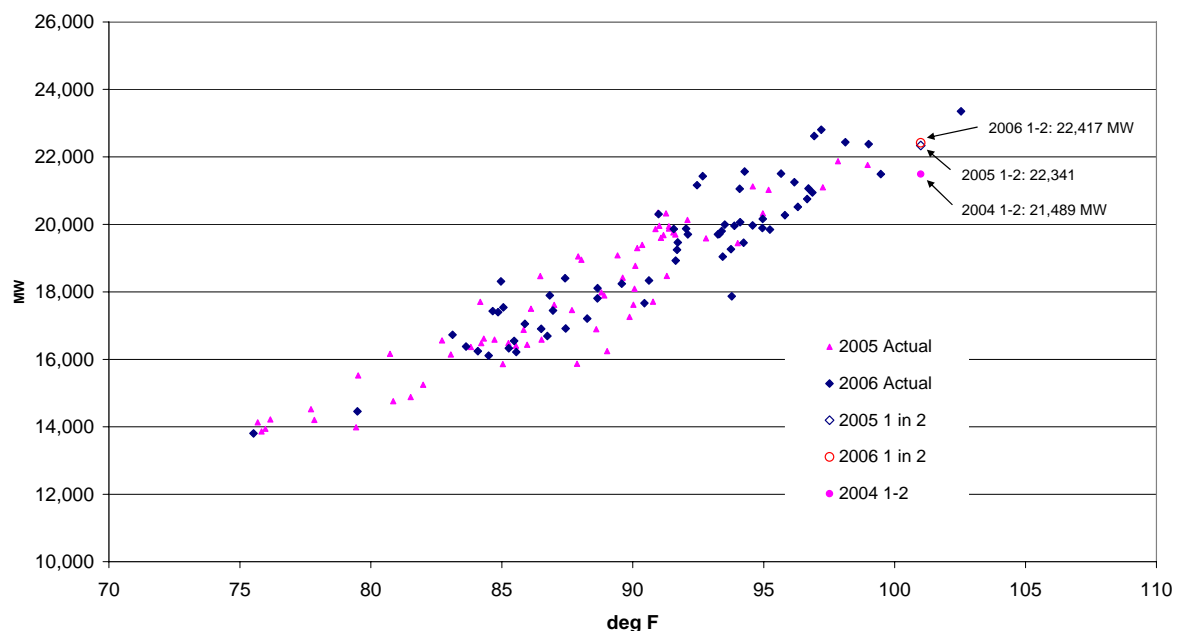


Table 5 shows the estimated coefficients used to calculate the weather-normalized peak and the resulting revised forecast. The estimated 1-in-2 2006 peak of 22,417 MW is 1.6 percent lower than the June 2006 Update projection. As a result, staff proposes to lower the SCE area forecast. Staff's forecast of 23,091 MW is more than 1,200 MW lower than the area forecast reported by SCE in its 2007 CPUC Long Term Procurement Plan filing.

Table 5: SCE Planning Area Forecast

Estimated Temperature-Load Statistics for 2006							
<i>Variable</i>	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Statistic</i>				
Intercept	-15,534.65	1,181.49	-13.15				
Weekend/Holiday	-2,343.02	143.46	-16.33				
631Max	400.33	15.18	26.38				
Divar	-69.36	15.86	-4.37				
Adjusted R Square	0.92						
Staff SCE Planning Area Forecast					SCE's 2007 IEPR Forecast		% Difference Staff/LSE Forecast 2008
	Weather Normalized 2006	2007	2008	% Increase above 1-in-2	2007	2008	
1-in-2	22,417	22,766	23,091		23,703	24,328	-5.08%
1 in 5	23,931	24,304	24,651	6.76%			
1 in 10	24,392	24,772	25,125	8.81%			
1-in-20	24,851	25,239	25,598	10.86%			

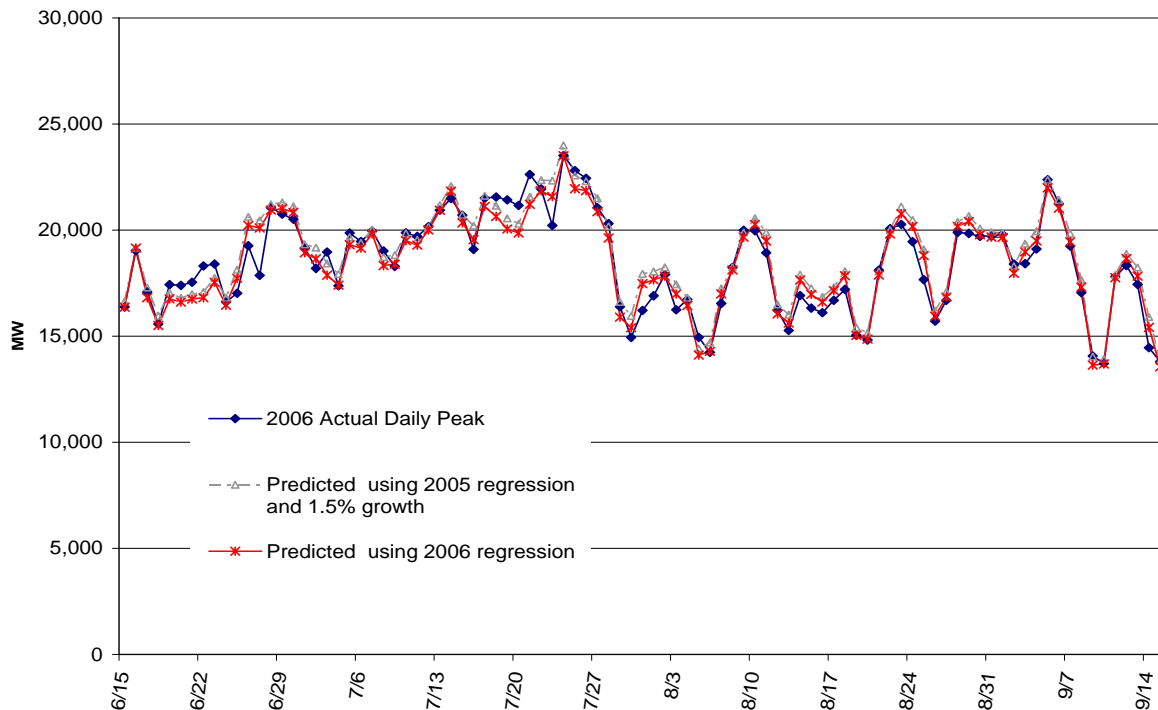
The difference between the staff and SCE forecasts largely reflects differences between their starting points and their projected annual growth rates. Staff's forecasted growth rate is 1.5 percent annually, compared with SCE's projected growth rate of 3 percent.

Table 5 also shows the staff forecast under extreme temperature conditions. Because the extreme temperatures of 2006 are included in the weather history used to predict load under increasing temperatures, the weather scenario multipliers have increased slightly.

Accuracy of Forecast

Figure 9 presents a comparison of the actual summer daily peaks with estimated daily peaks derived using both the 2006 estimation equation and the 2005 estimation equation grown at the 2005–2006 adopted forecast growth rate. The mean absolute percentage error estimated using 2006 weather and loads is 2.5 percent, with a standard deviation of 2.1 percent. The average error of the year-ahead method, using coefficients estimated from 2005 loads and temperatures, is slightly higher at 2.8 percent with a standard deviation of 2.4 percent.

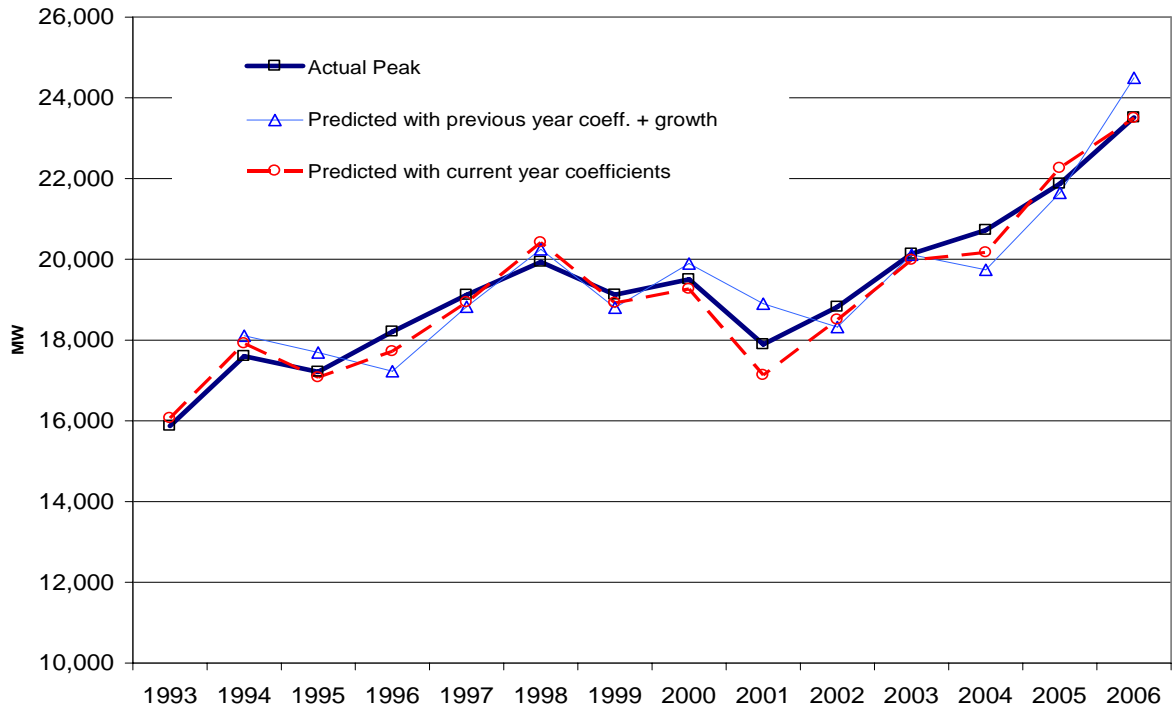
Figure 9: SCE 2006 Actual versus Predicted Daily Peaks



To evaluate the accuracy of the method used to develop the SCE year-ahead peak forecasts, staff compared the weather statistics which would have been estimated with past years' weather data with actual loads at that temperature. Staff estimated the weather coefficients for the SCE planning area for years for which daily maximum peaks are available, 1993 through 2006. From this data, the annual maximum peak (given the daily weather that actually occurred) is extracted. Figure 10 shows hypothetical year-ahead forecasts and actual annual peak demands.

The predictions of peak using current-year coefficients have an absolute average error of 1.8 percent. Using the previous years' coefficients with a forecasted growth rate increases the average error to 2.7 percent. The largest error is in 2001, when many electric customers voluntarily curtailed demand in response to the energy crisis.

Figure 10: SCE Actual versus Predicted Annual Peaks 1993–2006



SCE-Area LSE Forecasts

SCE's FERC Form 714 hourly loads include the loads of Anaheim, Azusa, Banning, Colton, Riverside, Vernon, and other smaller LSEs. Staff used historic loads for individual LSEs from both FERC Form 714 and California ISO hourly settlement data to estimate weather-adjusted peaks for individual LSEs. The 1-in-2 temperature values used to estimate the LSE weather-adjusted peaks are the average of those variables on days where the SCE area-wide annual maximum temperatures were average. For smaller LSEs for which no hourly load data is available, the peak is estimated from annual energy consumption. To estimate the weather-normalized load of SCE distribution customers, staff applied the same methodology used for the planning area to 2006 hourly loads submitted by SCE for the resource adequacy process. Finally, the sum of the individual LSE loads was calibrated with the SCE planning area total.

Table 6 shows staff's proposed forecast for the larger LSEs compared to the previous Energy Commission forecast. Forecasts for the POUs, which were not revised as part of the June 2006 update, have increased while the SCE service area forecast is lowered to be more consistent with current weather-normalized loads. The September 2005 disaggregate forecast tables relied upon actual load data only through 2003.

Table 6: 2008 Peak Forecast for SCE Area LSEs

LSE	June Update/ Sept. 2005 Forecast of 2006	Weather-Normalized 2006 Peak		% Change in Forecast	Staff Forecast of 2008	LSE Fore- cast of 2008	% Difference Staff/LSE Forecast
		Coincident	Non- coincident				
SCE Service Area	21,368	20,694	20,694	-3.2%	21,316		
City of Anaheim	473	579	588	22.4%	606	577	5.0%
City of Riverside	399	563	566	40.8%	583	573	1.7%
City of Vernon	164	175	200	6.7%	206		
Metropolitan Water Department	197	200	225	1.6%	232		
Total Other LSEs	190	205	207	8.2%	214		

Temperature-load relationships for the two largest POUs, Anaheim and Riverside, are shown below. In Riverside, 0 year-over-year growth was flat, similar to the SCE planning area as a whole. In Anaheim, the weather-adjusted peak grew at 1.5 percent.

Figure 11: Riverside Summer Weekday Peak versus Temperatures

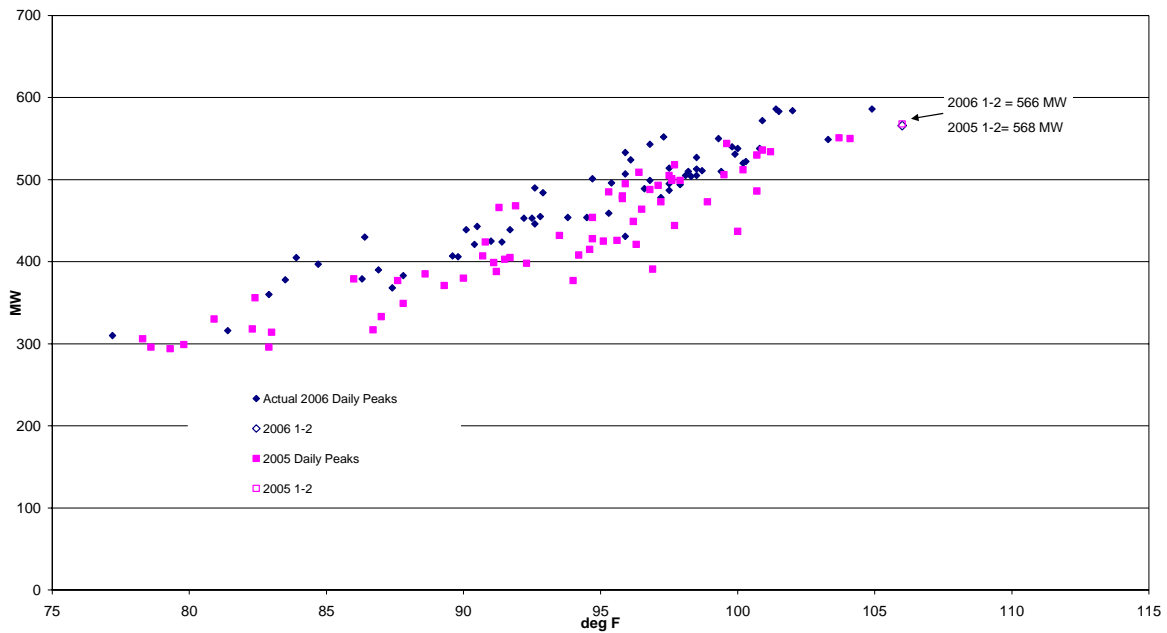
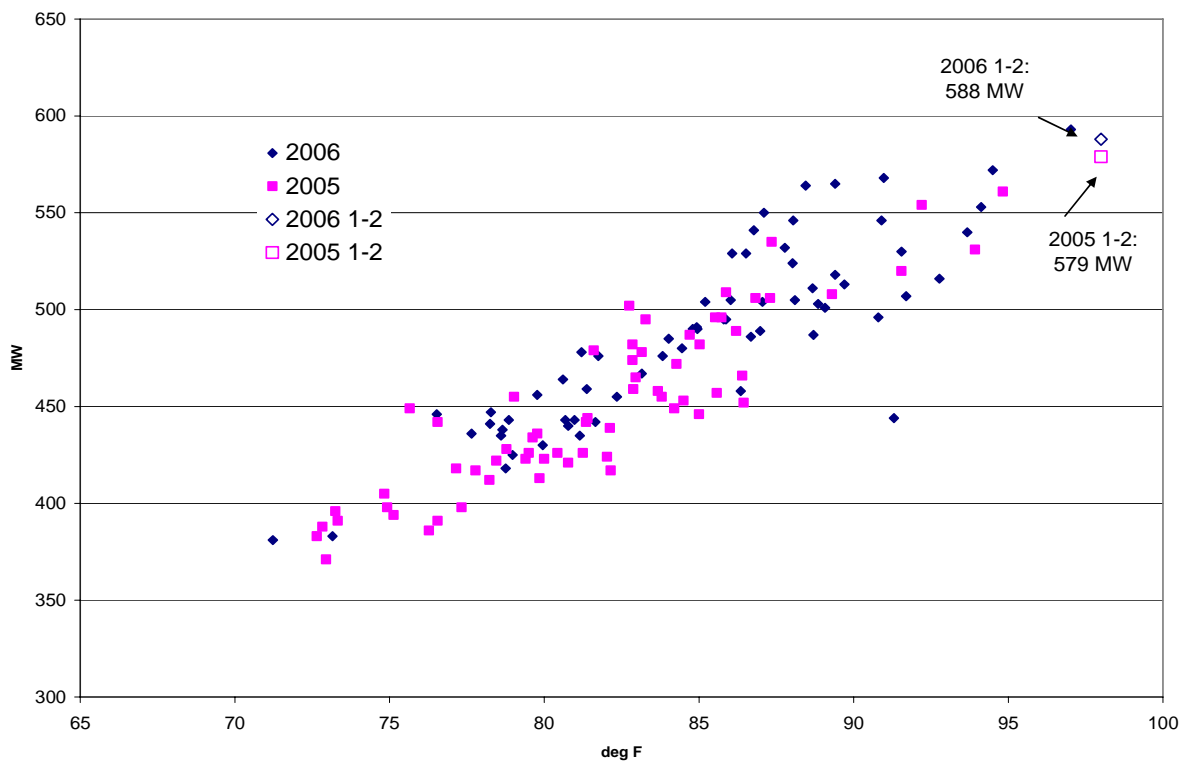


Figure 12: Anaheim Summer Weekday Peak versus Temperatures

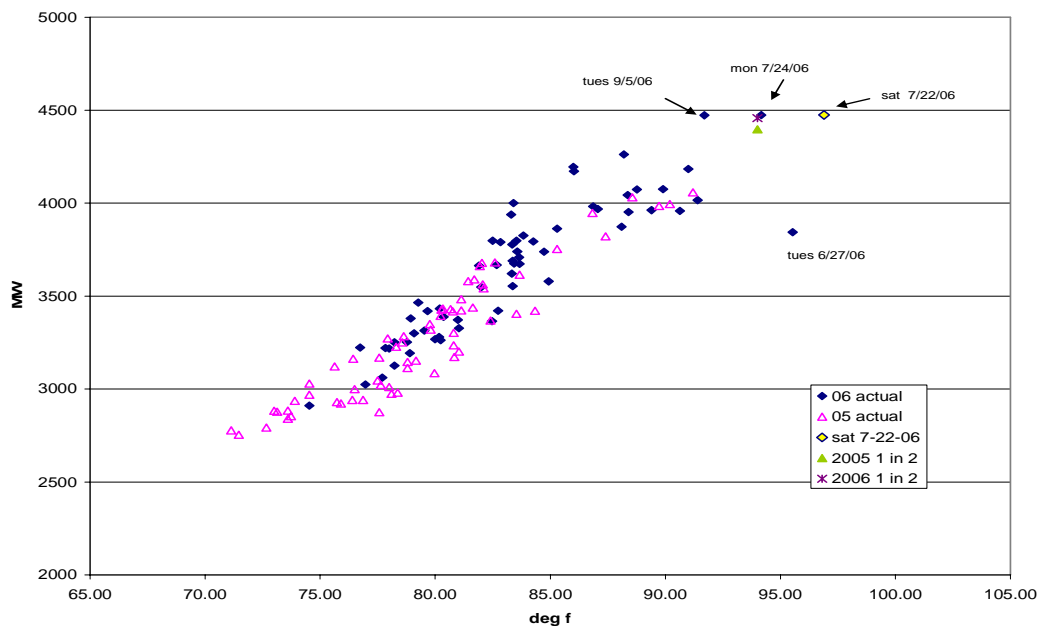


SDG&E PLANNING AREA RESULTS

The SDG&E planning area analysis used both lagged maximum temperature and daily diurnal variation. Staff also used a combination of Lindbergh Field, Miramar Marine Corp Air Station, and El Cajon weather stations to represent the SDG&E planning area. Because staff has no reliable weather information for El Cajon before 1979, the time period for historic analysis was limited to 1979–2006. Weather variables were calculated as the average of the three stations.

The diverse weather patterns during the summer of 2006 proved challenging when attempting to create a weather-normalized peak value. Summer 2006 produced three days in the SDG&E planning area with peaks within two MW of the annual peak, as shown in Figure 13. As in the previous utility areas, 2006 temperatures were generally warmer than in 2005.

Figure 13: SDG&E 2005–2006 Summer Weekday Temperature Peak Comparison

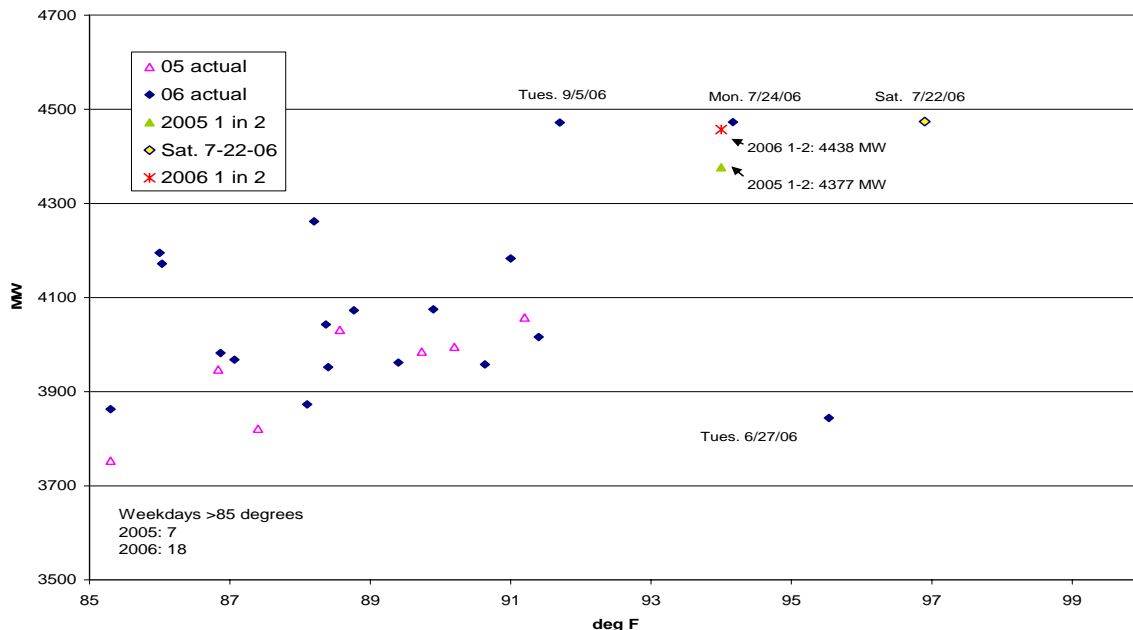


Two of these days occurred during the mid-July California heat storm, with the third occurring on September 5 (the day after Labor Day). Figure 14 provides a more detailed look at the higher temperature and load periods of the past two summers. During the July heat storm, the hottest day in the SDG&E planning area occurred on Saturday, July 22. This event produced the annual peak for SDG&E, which would have been higher had it occurred on a weekday. Temperatures for the SDG&E region had returned to near 1-in-2 levels by Monday, July 24, when the California ISO reached its statewide peak. Temperatures were slightly below annual 1-in-2 peak levels on the September peak day, but added loads from return-to-normal

business after the summer vacation period could have caused an increase in the daily peak. Demand observed on the second hottest summer day, June 27 adds to the SDG&E 2006 weather puzzle. Temperatures on this day were at the 1-in-2 level, but the associated loads were well below what would be expected, possibly because it was the first hot day of the summer. The fact that in 2005 there were only seven summer days with temperatures above 85 degrees, while 2006 had 18 such days may impact the difference in temperature response between in the two years .

Weather normalized peaks calculated with the method used in the June 2006 Update forecast indicate a 2005–2006 peak growth of 1.4 percent for the SDG&E planning area.

Figure 14: SDG&E 2005–2006 Summer Temperature-Peak Comparison for Temperatures above 85 degrees



The estimated 1-in-2 peak of 4,438 MW is 1.23 percent higher than the June 2006 Update projection for 2006. As a result, staff proposes to raise the SDG&E area forecast. Table 7 shows the estimated coefficients used to calculate the weather-normalized peak and the resulting revised forecast. The staff forecast is 1 percent greater than SDG&E's own forecast.

Table 7: SDG&E Planning Area Forecast

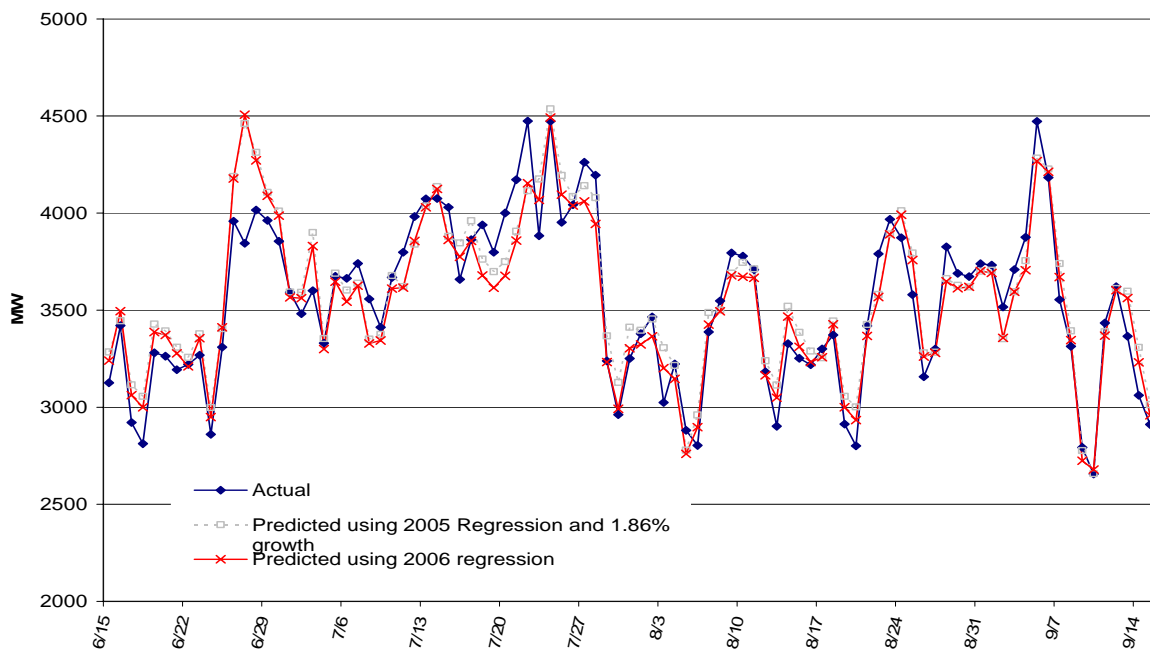
Estimated Temperature-Load Statistics for 2006							
		Coefficients		Standard Error		t Statistic	
Intercept		-3160.95		346.86		-9.11	
Weekend/Holiday		-457.42		34.85		-13.13	
SDGE631Max		83.78		4.74		17.66	
Divar		-10.72		4.58		-2.34	
Adjusted R Square		0.87					
Staff SDG&E Planning Area Forecast					SDG&E 2007 IEPR Forecast		% Difference Staff/LSE Forecast 2008
	Weather Normal-ized 2006	2007	2008	% Increase above 1-in-2	2007	2008	
1-in-2	4,438	4,504	4,595		4,471	4,546	1.07%
1 in 5	4,740	4,810	4,907	6.8%			
1 in 10	4,829	4,900	4,999	8.8%			
1-in-20	5,104	5,180	5,284	15.0%			

The difference between the staff and SDG&E forecasts largely reflects differences between the assumed 2006 weather-normalized starting point. Both forecasts projected 2006–2008 annual growth rates of approximately 1.7 percent annually.

Accuracy of Forecast

Figure 15 presents a comparison of actual summer daily peaks with estimated daily peaks derived using both the 2006 estimation equation and the 2005 estimation equation, grown at the 2005–2006 adopted forecast growth rate. Both the overestimation of the first warm summer period and the underestimation of the last warm summer period can be seen. Using 2006 weather and loads, the mean absolute percentage error is 3.2 percent with a standard deviation of 2.5 percent. The average absolute error of the year-ahead method, using coefficients estimated from 2005 loads and temperatures and the adopted forecast growth rate, is slightly higher at 3.6 percent, with a standard deviation of 2.7 percent.

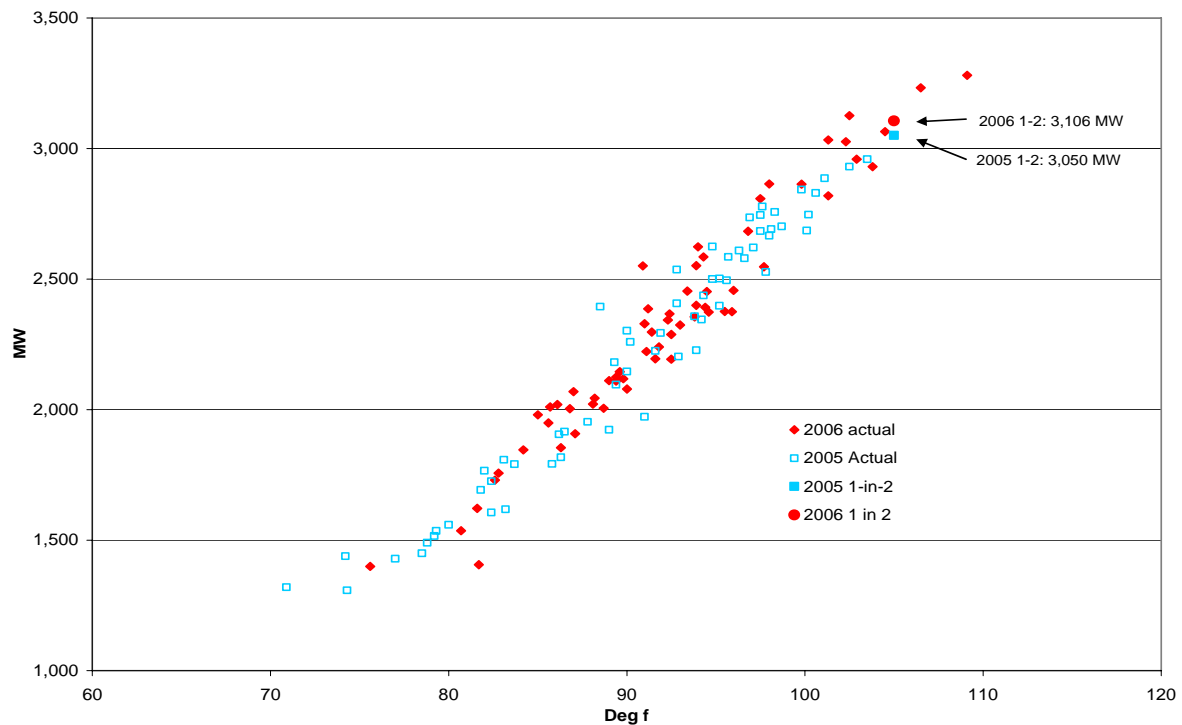
Figure 15: SDG&E 2006 Actual versus Predicted Daily Peaks



SMUD PLANNING AREA RESULTS

For the Sacramento Municipal Utility District (SMUD) planning area staff used the three-day lagged weighted average of daily maximum temperature as the primary explanatory variable. Figure 16 presents 2005 and 2006 summer weekday temperature and peaks. Also shown are each year's weather normalized 1-in-2 peak estimates. On average, 2006 summer weekday service area temperatures were somewhat higher than in 2005. Other than the difference in the higher 2006 peak week temperatures, the most notable difference is the group of temperatures on the low end of the range that were seen in 2005.

Figure 16: SMUD 2005 – 2006 Summer Weekday Temperature-Peak Comparison



The estimated 2006 1-in-2 peak is 3,105 MW, 3.7% percent higher than the 2006 forecast in the June 2006 update. Table 8 shows the estimated coefficients used to calculate the weather-normalized peak and the resulting revised forecast. The proposed staff peak forecast for 2008 is 130 MW higher than the forecast submitted by SMUD as part of the 2007 IEPR proceeding.

The distinction between the staff and SMUD forecasts reflects differences between the projected annual growth rates. Staff's forecast grows at 2.4% percent annually, compared to SMUD's growth rate of 2% percent. There may also be small differences in the assumed weather normalized starting point.

Table 8: SMUD Planning Area Forecast

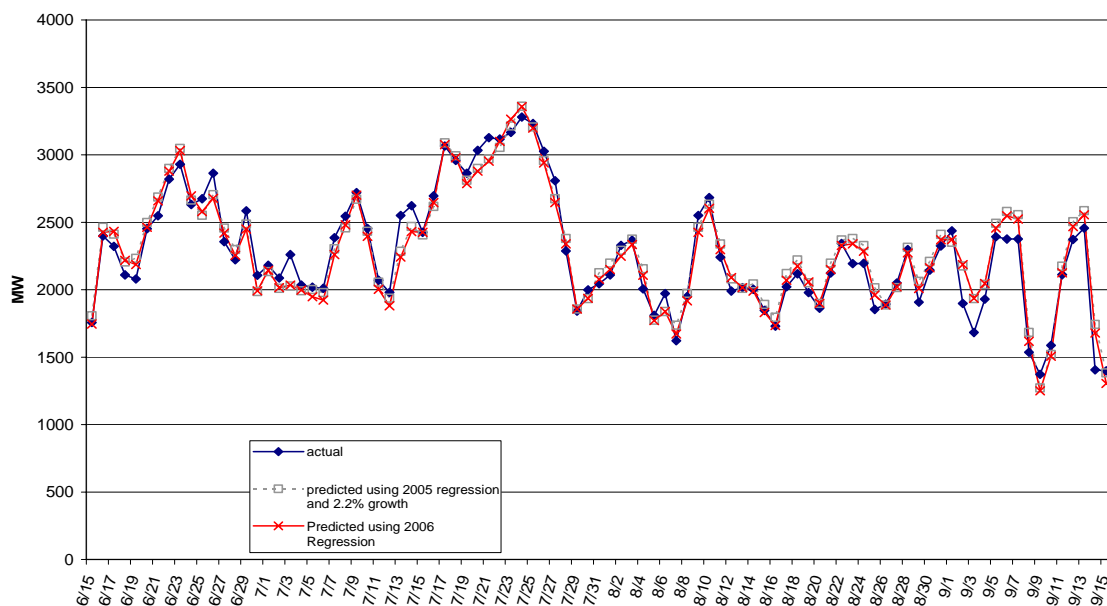
Estimated Temperature-load Statistics for 2006							
		Coefficients		Standard Error		t Statistic	
Intercept		-3,326.41		151.24		-21.99	
Weekend/Holiday		-140.57		23.29		-6.03	
SMUD631Max		61.26		1.63		37.52	
Adjusted R Square		0.94					
Staff SMUD Planning Area Forecast (MW)					SMUD's 2007 IEPR Forecast		% Difference Staff/LSE Forecast 2008
	Weather Normal-ized 2006	2007	2008	% Increase above 1-in-2	2007	2008	
1-in-2	3,106	3,175	3,252		3,060	3,122	4.16%
1-in-5	3,289	3,363	3,444	5.89%	3,159	3,223	6.88%
1-in-10	3,412	3,488	3,573	9.85%	3,254	3,320	7.62%
1-in-20	3,473	3,551	3,637	11.82%	3,324	3,391	7.25%

For the high temperature cases, the difference between the staff and SMUD forecasts is larger. The staff forecast increases by 9.85 percent under 1-in-10 temperatures, compared to SMUD's increase of 7.6 percent.

Accuracy of Forecast

Figure 17 presents a comparison of the actual summer daily peaks with estimated daily peaks derived using both the 2006 estimation equation and the 2005 estimation equation grown at the 2005–2006 adopted forecast growth rate. The mean absolute percentage error estimated using 2006 weather and loads is 3.8 percent with a standard deviation of 3.3 percent. The average error of the year-ahead method, using coefficients estimated from 2005 loads and temperatures, is slightly higher at 4.2 percent with a standard deviation of 3.5 percent.

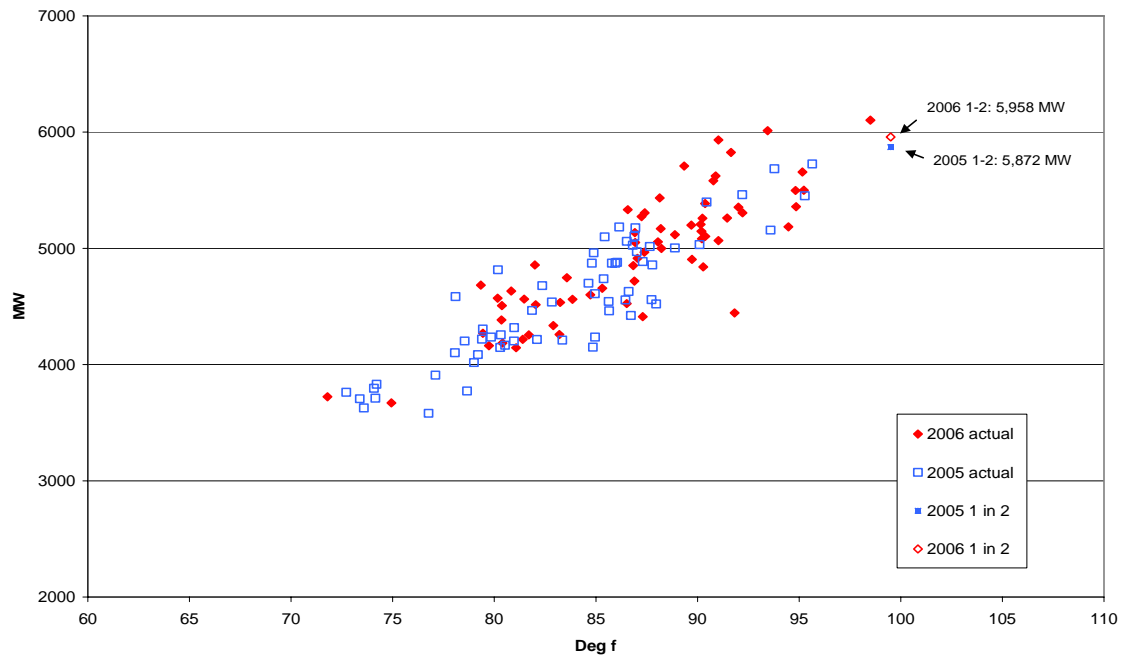
Figure 17: SMUD 2006 Actual versus Predicted Daily Peaks



LADWP PLANNING AREA RESULTS

For the Los Angeles Department of Water and Power (LADWP) planning area, staff used both the three-day lagged weighted average of daily maximum temperature and daily diurnal variation as explanatory variables. Figure 18 presents 2005 and 2006 summer weekday temperature and peaks. Also shown are each year's weather normalized 1-in-2 peak estimates. On average, 2006 summer weekday service area temperatures were somewhat higher than in 2005.

Figure 18: LADWP 2005 – 2006 Summer Weekday Temperature-Peak Comparison



The estimated 2006 1-in-2 peak is 5,958 MW, 3.1% higher than the 2006 forecast in the June 2006 update. As a result staff proposes raising the LADWP service area forecast.

Table 9 shows the estimated coefficients used to calculate the weather-normalized peak and the resulting revised forecast. The proposed staff peak forecast for 2008 is 381 MW (6.78%) higher than the forecast submitted by LADWP as part of the 2007 IEPR proceeding. The difference between the staff and LADWP forecasts reflects differences between the assumed 2006 weather-normalized starting point. LADWP uses a different set of weather stations that indicate 2006 was a more extreme weather year than indicated with the staff weather stations.

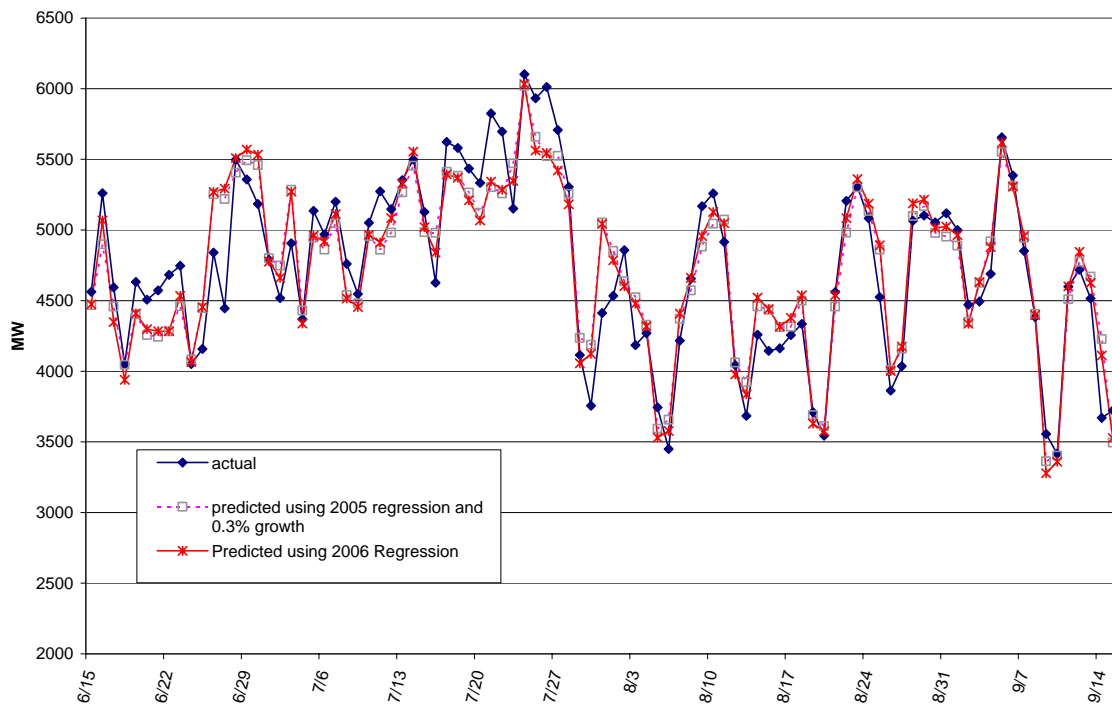
Table 9: LADWP Planning Area Forecast

Estimated Temperature-load Statistics for 2006							
		Coefficients		Standard Error		t Statistic	
Intercept		-3,455.98		452.09		-7.64	
Weekend/Holiday		-778.52		54.41		-14.31	
LADWP631Max		103.42		6.20		16.68	
LA divar		-26.48		6.36		-4.17	
Adjusted R Square		0.85					
Staff LADWP Planning Area Forecast (MW)					LADWP's 2007 IEPR Forecast		% Difference Staff/LSE Forecast 2008
	Weather Normaliz ed 2006	2007	2008	% Increase above 1-in-2	2007	2008	
1-in-2	5,958	5,977	5,999		5,557	5,618	6.78%
1-in-5	6,344	6,364	6,388	6.48%	5,945	6,010	6.29%
1-in-10	6,514	6,535	6,560	9.34%	6,065	6,132	6.98%
1-in-20	6,653	6,674	6,699	11.67%	6,169	6,237	7.41%

Accuracy of Forecast

Figure 19 presents a comparison of the actual summer daily peaks with estimated daily peaks derived using both the 2006 estimation equation and the 2005 estimation equation grown at the 2005–2006 adopted forecast growth rate. The mean absolute percentage error estimated using 2006 weather and loads is 3.95 percent with a standard deviation of 3.2 percent. The average error of the year-ahead method, using coefficients estimated from 2005 loads and temperatures, is slightly higher at 4.16 percent with a standard deviation of 3.28 percent.

Figure 19: LADWP 2006 Actual versus Predicted Daily Peaks



Statewide Forecast Tables

Table 10: 1-in2 Coincident Peak Demand by LSE

Area/LSE	2006 Weather-Normalized	2007	2008	Average Annual Growth 2006-2008
PG&E Service Area	19,523	19,807	20,057	1.4%
Silicon Valley Power	469	476	482	1.4%
Total NCPA	480	487	493	1.4%
Total Other LSEs in CAISO	257	261	264	1.4%
Dept of Water Resources - North	409	409	409	0.0%
Total North of Path 15	21,137	21,440	21,705	1.3%
	1,206	1,223	1,239	
Turlock Irrigation District Control Area	570	579	587	1.5%
Sacramento Municipal Utilities District	3,106	3,175	3,252	2.3%
Merced Irrigation District	77	78	79	1.4%
Central Valley Project	251	251	251	0.0%
Modesto Irrigation District	662	673	682	1.5%
City of Redding	244	247	251	1.4%
City of Roseville	331	336	340	1.4%
Shasta Dam Area Public Utility District	30	30	31	1.4%
Total SMUD Control Area	4,700	4,789	4,885	2.0%
Total PG&E Planning Area (excl. DWR & SMUD)	22,322	22,645	22,929	1.4%
SCE Planning Area	22,417	22,766	23,091	1.5%
City of Anaheim	579	588	597	1.5%
City of Riverside	563	571	579	1.5%
City of Vernon	175	178	180	1.5%
Metropolitan Water Department	200	203	206	1.5%
City of Azusa	63	64	65	1.5%
City of Colton	87	89	90	1.5%
Other Small LSEs	55	56	57	1.5%
Pasadena Water and Power	310	310	310	0.0%
San Diego Gas & Electric	4,438	4,504	4,586	1.7%
Dept of Water Resources - South	506	506	506	0.0%
Total South of Path 15	27,670	28,086	28,493	1.5%
Sum of Noncoincident Peaks in CAISO Control Area	48,807	49,526	50,198	1.4%
CAISO Coincident Peak	47,636	48,337	48,993	1.4%
LADWP	5,958	5,977	5,999	0.3%
Burbank	292	292	292	0.0%
Glendale	302	302	302	0.0%
Total LADWP Control Area	6,552	6,571	6,593	0.3%
Imperial Irrigation District	958	972	985	1.4%
Sum of Noncoincident Peaks	61,587	62,436	63,248	1.3%
Statewide Coincident Peak Demand	60,109	60,938	61,730	1.3%

Table 11: 1-in-10 Peak Demand by Area

Area/LSE		2007	2008
	PG&E Service Area	20,540	20,799
	PG&E Area CAISO LSEs	505	1,284
	Dept of Water Resources - North	409	409
Total North of Path 15		21,454	22,493
Turlock Irrigation District Control Area		600	609
	Sacramento Municipal Utilities District	3,488	3,573
	Other SMUD/WAPA LSEs	1,774	1,795
Total SMUD Control Area		5,261	5,367
Total PG&E Planning Area (excl. DWR &SMUD)		23,419	24,487
	SCE Planning Area	24,560	24,911
	Pasadena Water and Power	334	334
	San Diego Gas & Electric	4,902	4,992
	Dept of Water Resources - South	506	506
Total South of Path 15		30,303	30,742
Sum of Noncoincident Peaks in CAISO Control Area		51,757	53,235
CAISO Coincident Peak		50,515	51,957
	LADWP	6,535	6,559
	Burbank	319	319
	Glendale	331	331
Total LADWP Control Area		7,184	7,209
Imperial Irrigation District		972	985
Sum of Noncoincident Peaks		65,775	67,405
Statewide Coincident Peak Demand		64,196	65,787